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Witnesses:	M. Minick
	C. Silsbee
	G. Stern

SOUTHERN CALIFORNIA EDISON®

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(U 338-E)

TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY ON TRACK I ISSUES

Before the

Public Utilities Commission of the State of California

Rosemead, California
July 1, 2011

#1820470

TESTIMONY OF SOUTHERN CALIFORNIA EDISON COMPANY ON TRACK I ISSUES

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I.

INTRODUCTION

This Exhibit SCE-1 is Southern California Edison Company's (SCE) direct testimony volume addressing local capacity requirement (LCR) needs in SCE's service area. As such, it meets the requirements of the California Public Utilities Commission (Commission or CPUC) scoping rulings[1] that direct SCE, along with Pacific Gas and Electric Company (PG&E) and San Diego Gas and Electric Company (SDG&E) (collectively, Investor-Owned Utilities or IOUs), "to conduct a needs analysis for locally constrained areas."[2] This Exhibit SCE-1 also provides background information on various resource planning topics related to the system planning studies in this 2010 Long Term Procurement Plan (LTPP) proceeding and addresses a nuclear shutdown proposal initially raised in Track II of this proceeding.

The analysis developed in this testimony indicates that there is a wide range of potential local capacity needs in the Los Angeles (LA) Basin, depending on the particular assumptions made. For the purposes of system planning studies[3] that have also been studied as part of the current LTPP proceeding, SCE has assumed a local capacity need of 2,000 MW. But further detailed analysis is needed before SCE could feel confident that this 2,000 MW figure is correct. Therefore, SCE recommends that the Commission allow more time for the California Independent System Operator (CAISO) to complete detailed transmission studies that are within its purview before establishing local capacity needs for SCE.

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1 Order Instituting Rulemaking (R.) 10-05-006, dated May 6, 2010 and Assigned Commissioner's and Administrative Law Judge's Joint Scoping Memo and Ruling, dated December 3, 2010 (Scoping Ruling). These requirements have been further refined through additional rulings including Administrative Law Judge's Ruling Requesting Post-Workshop Comments, Updating Standardized Planning Assumptions, and Providing Lawrence Berkeley Report on Modeling Issues, dated December 23, 2010 and Administrative Law Judge's Ruling Modifying Track I Schedule and Setting Prehearing Conference, dated February 10, 2011.

2 Scoping Ruling, p.21.

3 *See* Exhibit IOU-1.

II.

OVERVIEW

The Scoping Ruling directed SCE to provide testimony on various system planning issues including a requirement to "…study four different RPS scenarios that achieve 33% [Renewables Portfolio Standard (RPS)] by 2020..."[4] and required that "[a]ll resource plans filed by the IOUs, or any respondent shall evaluate and document the performance of each in terms of cost, risk and GHG emissions metrics"[5] (defined in the Scoping Ruling as the Evaluation Criteria). SCE meets these other requirements through its participation in the development of other studies and testimony that are separately submitted in this LTPP proceeding. In particular, SCE participated in the preparation of two additional direct testimony volumes in this proceeding. Exhibit Joint IOU-1 includes an analysis of three IOU-developed resource planning scenarios (IOU Common Scenarios) and one sensitivity and provides the Evaluation Criteria for the three IOU Common Scenarios and the four scenarios mandated by the CPUC (CPUC-Required Scenarios). This exhibit is sponsored jointly by the IOUs and their consultant Energy and Environmental Economics, Inc. (E3).[6]

The IOUs also worked closely with the CAISO, which developed simulation data sets and performed detailed system modeling for the four CPUC-Required Scenarios. The IOUs used the CAISO data sets as the starting point for their own modeling runs for the IOU Common Scenarios. These modeling runs provided the input to an analysis of these scenarios sponsored by E3 in Exhibit Joint IOU-1, based on the Commission-directed Evaluation Criteria. SCE expects the CAISO to sponsor testimony in support of its modeling efforts for the four CPUC-Required Scenarios.

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4 Scoping Ruling, p.24.

5 *Id.* at p. 4, 65.

6 SCE provided utility-specific information to E3 to support some calculations of the evaluation criteria.

The CPUC-Required Scenarios vary in the manner in which a 33% RPS goal by 2020 is pursued, using scenario definitions and modeling assumptions developed by Energy Division staff. All of the scenarios are based on a California Energy Commission (CEC)-adopted load forecast and an assumed gradual retirement of coastal fossil-fired power plants. The scenarios vary based on their degree of reliance on wind resources (including variations in the amount of out-of-state wind resources) and their reliance on distributed renewable generation versus large scale renewable projects.

As described in Exhibit Joint IOU-1, the IOUs developed three IOU Common Scenarios that vary from the CPUC-Required Scenarios by using an IOU load forecast and an RPS procurement trajectory that incorporates recent IOU procurement activities, as well as a variety of other modifications. These scenarios vary by the retirement assumptions applied to coastal fossil-fired power plants, and the incorporation of LCR needs. Specifically, Scenario 3 assumes only El Segundo and Huntington Beach units 3 and 4 (which have announced retirement plans) will retire before the end of 2020, while Scenario 1 assumes that all the coastal fossil-fired plants in SCE's service area are shut down, but that 2,000 MW of additional fossil-fired power plants are built in SCE's service area to meet LCR needs in two local capacity areas (LCAs).[7] This additional power plant capacity is modeled as 1,000 MW of combustion turbines and 1,000 MW of combined cycle gas turbines (CCGTs). SCE is not at this time drawing any conclusions as to the specific kind of technology best able to meet LCR needs, or whether the LCR units would result from repower/refurbishment of existing coastal power plants or new developments.

Section III of this testimony estimates the total LCR need range in the SCE Los Angeles basin region at 12,260 MW to 13,260 MW in 2020 and describes how SCE arrived at an LCR

[7] SDG&E has also identified LCR needs but no definitive value was determined. So, 300 MW was included in its service area as input for the IOU Common Scenarios. Since these LCR needs are not related to the potential for coastal fossil-fired generating plants in SCE's service area to shut down, the SDG&E LCR needs are reflected in all the IOU Common Scenarios.

deficiency of about 2,000 MW for the base case in the LA Basin. As described further below, there is a relatively wide uncertainty bound associated with this possible LCR deficiency. Table I-1 summarizes SCE's LCR needs and the corresponding uncertainty ranges. Negative values indicate need.

Table I-1
Summary of Estimated LCR Need in SCE's Area

Local Capacity Area	Low Need Sensitivity (MW)	Base Need (MW)	High Need Sensitivity (MW)
L.A. Basin	-495	-1,936	-6,431
Ventura/Big Creek	1,296	978	43

Section IV provides an overview of the resource planning process and how the LTPP process differs from traditional integrated resource planning (IRP) analyses conducted in regulatory jurisdictions, and includes a discussion regarding modeling needs and modeling techniques associated with resource planning analyses. Much of the modeling work in Track I of this LTPP proceeding has focused on renewable integration needs associated with a buildout to 33% renewable energy. Unlike past LTPP proceedings, the modeling methods used in the 2010 LTPP are far more sophisticated and capable of assessing resource needs related to renewable integration requirements (ramping and regulation) in addition to overall system capacity needs (planning reserve margin). Because renewable integration needs and products are currently procured through short-term CAISO markets, the CAISO has actively participated in this proceeding. The CAISO, with support from SCE and other stakeholders, has developed techniques to evaluate renewable integration needs using a PLEXOS dynamic optimization model. Section III provides a basic description of how this modeling is performed, how it fits into the context of resource planning, and why this modeling is necessary.

Section V briefly discusses the potential impacts of San Onofre Nuclear Generating Station Unit Nos. 2 and 3 (SONGS 2 & 3) shutdown and focuses on why such potential impacts are beyond the scope of this Track I of the LTPP.

III.

LOCAL CAPACITY REQUIREMENTS NEEDS

This section describes how SCE developed a modeling assumption that 2,000 MW of fossil-fired generating capacity is needed in SCE's service area by 2020 to augment the capacity that is needed for LCR. Because the renewables portfolio buildout has little impact on the LCR, SCE has not specifically calculated LCR needs for each CPUC-Required and IOU Common Scenario. Instead, SCE has calculated high and low case values that are sufficient, in SCE's opinion, to span the range of variation across the various scenarios that are analyzed in Exhibit IOU-1.

At the outset, it is important to note that SCE is not directly responsible for determining LCR needs in its service area. The CAISO conducts annual LCR studies, which the Commission reviews in Commission Resource Adequacy (RA) proceedings. In addition to these annual RA studies, the CAISO conducts multi-year forward studies of resources needed for reliable grid operations, and has an ongoing stakeholder process (in which SCE is an active participant) to investigate a variety of grid reliability topics.

Many of the CAISO studies involve transient stability analysis, complex power flow modeling or similar analysis, typically performed for a single peak period ("hour"). These studies test specific performance attributes, such as whether transformers or transmission lines are overloaded, or whether voltage is adequate and stable under normal and transient conditions. While SCE's transmission planning organization has the modeling capability to perform all of these kinds of studies, the amount of time these studies require (typically from six months to well over a year) has made it impractical for SCE to perform power flow and stability simulations to assess LCR needs under the scenario assumptions being used in the LTPP within the time provided by the LTPP schedule.[8] Additionally, SCE is not necessarily privy to all of the data

[8] *See* Prehearing Conference Statement of Southern California Edison Company, dated December 16, 2010.

from market participants that the CAISO has. So, SCE cannot necessarily do exactly equivalent transmission modeling to the CAISO. Instead, SCE has relied on a spreadsheet calculator developed by the CAISO with input from the CPUC and CEC to assess LCR needs for modeling purposes.

A. Why LCR Analysis is Necessary

The CAISO must operate the electrical grid to meet or exceed national, regional, and state standards for providing a reliable and stable supply of electricity to customers. The CAISO conducts numerous types of studies to ascertain whether the electricity grid will perform adequately under normally-occurring stress conditions (*e.g.*, one-in-ten peak load conditions), as well as under contingency conditions where key transmission and generation assets are out of service. At the federal level, the North American Electric Reliability Corporation is empowered to adopt standards subject to the approval of the Federal Energy Regulatory Commission and to enforce these standards through various actions, including fines for non-compliance.[9] The CAISO is expected to manage the grid without involuntary customer load curtailments except under extremely unlikely multiple-asset failure conditions. At the state level, the CAISO is responsible for the efficient use and reliable operation of the transmission grid.[10] To comply with these requirements, CAISO must meet numerous transmission planning and system operating criteria. One of these criteria is to have sufficient local resources available (*i.e.*, meeting the LCR need) to successfully meet the system grid operability requirements in the event key transmission lines or generating facilities are unavailable to serve load in individual local capacity areas (LCAs or local areas). The consequences of not having sufficient local capacity is generally that the CAISO would be required to curtail customer loads in the local area in the event that the contingent conditions occur.

9 This authority is based on provisions of the Energy Policy Act of 2005, with regulations generally appearing at 18 CFR 40.

10 *See generally,* Cal. Pub. Util. Code §345 *et. seq.*

B. The LCR Issue in the LA Basin and Ventura/Big Creek LCAs

There are two primary LCAs within SCE's service area, the LA Basin LCA and the Ventura/Big Creek LCA. The LA Basin LCA is the major load center for SCE, municipal utilities, and direct access providers.[11] The LA Basin transmission system has been developed over the last 60 years to be very robust and is an interconnected grid that has reliably served customers' energy delivery needs. In order to successfully meet federal, Western Electricity Coordinating Council (WECC), and CAISO grid operating criteria, careful planning related to the amount of generation likely to be available and of the location of high voltage transmission system wires and other equipment, must be completed well in advance of making significant changes to this existing interconnected grid. Since SCE imports a significant amount of power into the LA Basin LCA due to economic and reliability reasons, the system must be robust enough to allow for such imports while meeting grid requirements such as voltage support and stability.

LCR needs are essentially generation that is generally closer to load, which is necessary to meet the physical operating needs of the system including maintaining voltage levels and providing for reliability of the electric transmission system during certain outages of key elements of both generation and transmission. To this end, the CAISO transmission planners, often working with SCE's transmission planners, study the electric system configurations to determine how best to meet these mandatory grid reliability criteria. After extensive analysis, the CAISO determines the amount of LCR generation need based on a specific set of assumptions. The difficult part of a longer term analysis is determining these input assumptions because generation and load assumptions can vary more dramatically the further into the future

[11] SCE is aware that the CAISO is considering narrowing the LA Basin LCA designation to include only loads and resources in the western portion of this geographic area, and calling the new area the Western LA Basin LCA. However, the Load & Resources (L&R) tool as currently configured does not allow the implications of this change to be assessed. The CAISO has also not yet finalized its decision to separate the Los Angeles local capacity area into Western and Eastern areas.

that is modeled. As there is a significant amount of load in the LA Basin, and the expansion of transmission facilities in a dense urban area would be very challenging, this area has relatively high LCR needs. The CAISO estimates the current LCR need in the LA Basin LCA to be around 10,865 MW or about 40% of overall CAISO LCR needs.[12]

The challenges in the Ventura/Big Creek LCA are somewhat different. This LCA spans areas somewhat distant from the local load center, and local generation is necessary to assure that loads can be adequately served when transmission lines serving these areas are out of service.

C. Assumptions Used to Determine SCE Service Area LCR Needs

1. Methodology

Because a full blown power flow analysis is impractical given the schedule of the LTPP, SCE used the most recent version of the CAISO's Load and Resources Analysis (L&R) tool (released in December 2010) to perform its LCR analysis. According to the CAISO,[13] the L&R tool is intended to identify potential resource shortages in selected LCAs and larger regions when gas-fired generation units using Once Through Cooling (OTC) technology may come offline to retrofit, repower or retire in response to State Water Resources Control Board (SWRCB) regulations. This tool contains data for the years 2011 through 2020 and focuses on four principal LCAs inside the CAISO control area: the Bay Area, the LA Basin, Big Creek/Ventura, and San Diego. The L&R tool calculates the annual surplus or deficit of LCR need for each area by subtracting the LCR for that area from the total capacity of all the generating resources on-line in that area. Standardized planning assumptions are built into the model, sometimes allowing the user to choose from a menu of alternative assumptions. It is also possible for the user to override some of the standardized assumptions.

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12 CAISO 2012 Local Capacity Technical Analysis Draft Report and Study Results, dated April 7, 2011. *See* http://www.caiso.com/2b59/2b59bdc315490.pdf. This is slightly higher than the LA Basin LCR shown in the CAISO's spreadsheet calculator, which is based on a 2011 study.

13 The L&R tool and supporting documentation are available from the CAISO. *See* http://www.caiso.com/1c58/1c58e7a3257a0.html

The tool calculates each area's LCR in MWs for years 2011 through 2020. The tool also accounts for any expected new or upgraded transmission projects that could affect the LCR requirements in the area. The tool cannot be used to conduct full, or robust, LCR studies, which require load flow and other detailed transmission modeling analysis, for each year from 2011 to 2020, but the tool can provide a reasonable indication of the LCR needs. Instead of a power flow analysis, the tool takes as its base the 2011 LCR need for each area and escalates it for each year by the increase in 1-in-10 peak load from the previous year. It then adjusts the resulting number by subtracting any transmission improvements in the given region that would reduce the LCR for that region. The CAISO calculates the base 2011 LCR need using the LCR assessment documented in the CAISO's *2011 Local Capacity Technical Analysis.*[14]

2. Load Forecasts

The L&R tool uses the CEC's 2009 Integrated Energy Policy Report (IEPR) 1-in-10 forecasted summer peak load conditions as a base assumption.[15] The *2011 Local Capacity Technical Analysis* uses the 2009 IEPR adopted loads broken down into LCAs by the CEC for use in the LCR analysis. SCE did not make any changes to the loads utilized in the tool. The 2009 IEPR load forecast is lower than the load forecast chosen in the IOU Common Scenarios.[16] Since a basic assumption of the L&R tool is that LCR needs grow proportionate to load growth, SCE's results are somewhat understated relative to the load forecast included in the IOU Common Scenarios.

14 *See* http://www.caiso.com/1c44/1c44b8e0380a0.html

15 California Energy Commission, California Energy Demand 2010-2020: Staff Revised Demand Forecast, Second Edition, CEC-200-2009-012-SF-REV, November 2009, pp.236-237. *See* http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-SF-REV.PDF

16 The IOU Common Scenarios assume a levelized annual load growth of 0.76%. In contrast, the CPUC-Required Scenarios assume annual load growth of just 0.2% (after Demand-Side Achievements).

3. Existing and Forecast Capacity

The tool calculates the available generating capacity for each area using a listing of specific generation resources that are assumed in each area, based on the net qualifying capacity (NQC) value of these resources. According to CAISO documentation for the L&R tool, the generation resources are compiled from the final 2011 NQC list posted on the CPUC's website.[17]

4. Input Selections and Data Modifications

The L&R tool has six key input categories that the user may select, as follows:

1) Load Modifier;

2) Renewable Construction;

3) OTC and Other Retirement;

4) New Generation Construction;

5) New Transmission Construction; and

6) 33% RPS Compliance Year.

Within each input category, the L&R tool lists two or more options where the user may choose preset options with data supplied by the CAISO. Figure III-1 below details the six input categories and the options embedded within each.

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17 *See* http://www.cpuc.ca.gov/NR/rdonlyres/A017578D-7420-4ABD-A0F6-2BF5EE335F10/0/CPUCFinal2011NQClist.xlsx

Figure III-1
L&R Tool Standard and Alternative Assumptions

Load Modifier Scenarios	Renewable Construction Scenarios	33% RPS Compliance Year
High Net Load	Trajectory Case	2020
Mid Net Load	Environmentally Constrained	2022
Low Net Load	Cost-Constrained	2025
	Fastest Timeline	
	ISO Hybrid Portfolio (2020)	

Retirement Scenarios	New Gen Construction	New TX Construction
None	None	None
OTC and some Non-OTC retirements	Under Construction Generation	Under Construction Transmission
OTC/Retiring Generation	AFC Permitted Generation	CPCN Permitted Transmission
	Contracted Generation	TPP Approved Transmission
		Proposed Transmission
		Conceptual RPS Transmission

a) Load Modifier

The tool allows the user to input forecasts for four types of load modifiers: Demand Response (DR), California Solar Initiative (CSI), Combined Heat and Power (CHP), and Energy Efficiency (EE). For each load modifier, the user can input a high, medium, and low forecast. Depending on which option is selected by the user, the corresponding load modifier is subtracted from the area load forecast to determine net load.

Table III-2 and Table III-3 below detail the load modifiers that SCE input into the L&R tool for the LA Basin and the Big Creek/Ventura regions. The CEC's 1-in-10 peak load forecast does not include DR, which is treated as a supply resource, so the DR load modifier is based on a forecast of available DR capacity. The CEC forecast includes self-generation (*i.e.*, CSI and customer CHP) and EE in its load forecast. SCE has included modifications to incremental EE[18] and DR[19] beyond what was included in the 2009 IEPR consistent with SCE's forecasts.

[18] *See* Exhibit Joint IOU-1, p.22.

[19] *See id.* at p.26.

Table III-2
Load Modifiers for LA Basin (MW)

LA Basin	Demand Response 2011	Demand Response 2020	CSI 2011	CSI 2020	CHP 2011	CHP 2020	Energy Efficiency 2011	Energy Efficiency 2020
High Net Load	1148	968	0	0	0	0	0	-1206
Mid Net Load	1157	1589	0	0	27	268	0	-744
Low Net Load	1167	2211	0	110	86	504	0	-282

Table III-3
Load Modifiers for Big Creek/Ventura (MW)

Big Creek/ Ventura	Demand Response 2011	Demand Response 2020	CSI 2011	CSI 2020	CHP 2011	CHP 2020	Energy Efficiency 2011	Energy Efficiency 2020
High Net Load	262	220	0	0	0	0	0	-260
Mid Net Load	264	361	0	0	5	55	0	-160
Low Net Load	266	502	0	28	20	104	0	-61

b) Renewable Construction

The L&R tool allows the user to select one of the four CPUC RPS buildout cases or a CAISO hybrid case. SCE observed that the selection of a RPS buildout case has little impact on LCR needs (less than 30 MW in 2020 for the LA Basin LCA and no variation in the Ventura/Big Creek LCA), so the SCE used the Trajectory Case for all the analyses of LCR need presented in this testimony.

c) OTC and Other Retirement

The L&R tool gives the user the ability to select between three retirement schedules associated with older generating plants. The "None" option results in no retirements. Selecting the "OTC/Retiring Generation" option causes all the generating plants relying on OTC technology to be retired, except the nuclear facilities. Selecting the "OTC and Some Non-OTC Retirements" option causes all plants on the SWCRB compliance schedule (which does not include the nuclear facilities) to be retired on their listed compliance date and some non-OTC units as discussed below. Of course, this is a conservative approach since SWCRB regulations do not require the retirement of OTC facilities.

In the LA Basin LCA, the L&R tool identifies Etiwanda Generating Station Units 3 and 4 and several smaller generating facilities as the non-OTC plants assumed to retire prior to 2020. There are no plants assumed to retire prior to 2020 in the Ventura/Big Creek LCA. Since the CAISO's PLEXOS simulation data set assumes continued operation of these non-OTC plants through 2020, and because SCE is not aware of any retirement plans, SCE did not use the "OTC and Some Non-OTC Retirement" option. Thus, SCE used the "OTC Retirement" generation option in all the analysis of LCR need presented in this testimony.

Table III-4 shows the OTC units included in the L&R tool for SCE service area LCAs The tool's default OTC retirement schedule is based on the SWRCB compliance schedule, which requires most of the current OTC fossil-fired coastal plants in SCE's service area to retire or mitigate the use of OTC technology by the end of 2020. However, for OTC plants retiring in response to the adopted SWRCB regulation, the CAISO L&R tool accelerates the date of retirement to the beginning of 2020. This allows for use of 2020 as a proxy for 2021, the first year the CAISO system would be without the LCR contributions of these plants.

Table III-4
Generation Stations Using OTC Technology in the L&R Tool

Local Capacity Area	Unit Name	MW
LA Basin	Alamitos	2,010
LA Basin	Huntington Beach	904
LA Basin	El Segundo	670
Big Creek/Ventura	Mandalay	430
Big Creek/Ventura	Ormond Beach	1,516
LA Basin	Redondo Beach	1,356

d) New Generation Construction

The L&R tool includes a schedule of planned generation additions that are expected to come on-line between 2011 and 2020. The L&R tool classifies each generator addition according to where it is in the approval and construction process. Generators are classified as either "Contracted," "Application For Construction (AFC) Permitted," or "Under Construction." The user can then select how restrictive the L&R tool is in adding generation in the interim years from these 3 options. The "None" option assumes no new generation comes on-line at any time. The "Under Construction" option adds only generators that are considered under construction at the time of the updated L&R tool's release in December 2010, while the "AFC Permitted" option includes both generation that is under construction, as well as generation that has been approved following the submittal of an AFC. The scenario "Contracted Generation" includes all of the above mentioned generating units, as well as generators that have contracted with load-serving entities, but have not yet been approved following submittal of an AFC. Table III-5 lists the new potential new generating units and their expected Commercial Operating Dates (CODs) in the LA Basin and Big Creek/Ventura regions between the beginning of 2011 and the end of 2020.

Table III-5
Potential New Generating units in the LA Basin and/ or Big Creek/Ventura Regions

Local Capacity Area	Scenario	Facility Name	NQC (MW)	COD
LA Basin	Under Construction	Canyon Power Plant	200	2012
Big Creek-Ventura	Under Construction	Chiquita Canyon Landfill	9	2011
Big Creek-Ventura	Contracted Generation	Delano 2	49	2015
LA Basin	Under Construction	El Segundo Repower	560	2012
LA Basin	Under Construction	Riverside Energy Resource Units 3&4	96	2011
LA Basin	Contracted Generation	Sentinel	750	2015
LA Basin	AFC Permitted Generation	Walnut Creek Energy Cntr	470	2013

The L&R tool credits the NQC from these units in the year they come on-line to the total existing NQC in each unit's respective area. This results in a larger total NQC in the region and a smaller LCR deficit for that area (or a greater surplus, if a surplus exists).

SCE did not make any changes to the list of new generation resources or the listed commercial operating dates in the CAISO L&R tool. However, the designation of the Sentinel units was corrected to show that these units are in the LA Basin LCA.[20]

e) New Transmission Construction

As with New Generation Construction, the L&R tool classifies new transmission by stage of development. The options that the user can select comprise: (1) "None," which adds no new transmission beyond what currently exists; (2) "Under Construction Transmission," which adds transmission that is under construction at the time of the development of the L&R tool; (3)

20 SCE notes that five of the units on the Sentinel site are commonly called "Sentinel units," and three of the units are commonly called "Ocatillo units." Based on the capacity shown in the L&R tool, SCE concludes that the CAISO's designation of "Sentinel" refers to all eight units on the Sentinel site.

"Certificate of Public Convenience and Necessity (CPCN) Permitted Transmission," which adds transmission with a CPCN approved by the CPUC; (4) "Transmission Planning Process (TPP) Approved Transmission," which adds transmission that is approved through the CAISO's transmission planning process; (5) "Proposed Transmission," which adds transmission to meet the 33% RPS; and (6) "Conceptual RPS Transmission," which adds transmission that was identified as part of a CPUC 33% RPS study. Renewable projects tied to future transmission are not identified as projects on the list of generator additions in the L&R tool. Instead, they are added to the capacity available to the LCA when the associated transmission line is selected for completion. The only transmission line project listed in the L&R tool that impacts SCE's LCR needs is the Tehachapi project, which is currently under construction. Table III-6 shows the capacity additions attributed to the construction of this project.

Table III-6
Future transmission affecting the LCR need of the LA Basin and Big Creek/Ventura regions

Region	Project Name	Scenario	NQC (MW)	COD
Big Creek-Ventura	Tehachapi Transmission	Under Construction	578	2013
LA Basin	Tehachapi Transmission	Under Construction	1000	2014

f) 33% RPS Compliance Year

SCE uses 2020 as the year in which RPS compliance is achieved on a physical basis, to be consistent with the assumptions in the IOU Common Scenario analyses presented in Exhibit Joint IOU-1. This is a more aggressive assumption than is likely, since SCE currently anticipates achieving a portion of its 33% goal (associated with bundled procurement) through flexible compliance mechanisms.

D. Results

SCE used the L&R tool to develop a base case analysis, and sensitivity cases that bracket high and low ranges of LCR needs in 2020. The total LCR need ranges from 12,260 MW to

13,260 MW for the LA Basin and from 2,781 MW to 3,359 MW for the Big Creek/Ventura LCA. The L&R tool produced the following range of deficiencies (-) and surpluses in the LA Basin and Big Creek/Venture LCA.

Table III-7
LCR Need Range for LA Basin and Ventura/Big Creek LCAs (MW)

LCR Need (2020) MW	**Low**	**Base**	**High**
Los Angeles Basin	-495	-1,936	-6,431
Ventura/Big Creek	1,296	978	43

Note: (-) indicates a deficiency or need for additional resources

For modeling purposes in the IOU Common Scenarios, SCE used a rounded value of 2,000 MW of LCR deficiency for the LA Basin. In SCE's judgment, this is a reasonable value to use in a scenario analysis to account for LCR resources. In the IOU Joint Analysis described in Exhibit Joint IOU-1, this 2,000 MW deficiency for LCR purposes is split equally between Combustion Turbine (CT) peakers and 50% CCGTs, since previous studies conducted by the CAISO indicated that using a combination of resource types lowered the amount of integrating resource need. However, more detailed analysis of LCR deficiency, which CAISO is in the process of performing, is required before adopting any specific value for procurement purposes.

Table III-8 below describes the assumptions selected in the L&R tool for SCE's high, low and base cases for determining the LCR determination in its service area:

Table III-8
Assumptions Selected in SCE's High, Low, and Base Cases For LCR Determination In LA Basin and Big Creek/Ventura LCAs

Load Modifier	Low-Net Load	Mid-Net Load	High-Net Load
Renewable Construction	Trajectory Case RPS Buildout	Trajectory Case RPS Buildout	Trajectory Case RPS Buildout
Retirement	Fossil plants affected by SWRCB OTC compliance retire by 2020	Fossil plants affected by SWRCB OTC compliance retire by 2020	Fossil plants affected by SWRCB OTC compliance retire by 2020
New Generation	All Contracted Generation is Built	All Contracted Generation is Built	No New generation
New Transmission	All Under-Construction Transmission is Built	All Under-Construction Transmission is Built	No New transmission
33% RPS Compliance Year	2020	2020	2020

In order to create a range of possible LCR surpluses or deficits for the LA Basin and Big Creek/Ventura LCAs, SCE changed the various user options in the L&R tool to produce low and high values of LCR need. The low need case varied from the base assumptions by using the Low Net Load modifier. The high need case varied from the base assumptions by using the High Net Load modifier, and assuming no new generation or transmission construction. SCE does not consider the assumptions used in the high and low cases as likely to occur; rather they are simply optimistic and pessimistic assumptions designed to test sensitivities.

Figure III-2 and Figure III-3 below summarize the calculation of LCR need/surplus in the LA Basin and Ventura/Big Creek LCAs. This calculation starts with the 2009 IEPR load forecast in each LCA, adjusted for new transmission (Lines 1 and 2), and uses the forecasted load growth to increase 2011 LCR needs (Line 3). Next, available capacity in each LCA (Line 4) is adjusted based on L&R tool options (Lines 5 through 8). Finally, the difference between LCR needs (Line 3) and adjusted available capacity (Lines 4 through 8) is shown (in Line 9) as a net LCR surplus (+) or net LCR need (-).

Figure III-2
LCR Need in the LA Basin Area (in MW)

		Low Need Sensitivity		Base Need		High Need Sensitivity	
		2011	2020	2011	2020	2011	2020
1	1 in 10 Peak Load (latest IEPR, split to Area)	20,164	22,836	20,164	22,836	20,164	22,836
2	Transmission improvements that affect LCR	0	1000	0	1000	0	0
3	LCR	10589	12260	10589	12260	10589	13260
4	Total Net Qualifying Capacity in area as of 2010 plus new additions from scenarios (including supply side CHP additions)	11955	14361	11896	14125	11757	11757
5	Renewable Construction Scenarios including Potential New Renewable Resource Additions related to Conceptual RPS Transmission	0	12	0	12	0	12
6	Incremental Preferred Demand Side Management	86	332	27	-476	0	-1206
7	Demand Response Resources	1167	2211	1157	1589	1148	968
8	Retirements	0	4927	0	4927	0	4927
9	**Surplus or deficiency**	**2619**	**-271**	**2491**	**-1936**	**2316**	**-6655**

Surplus or Deficiency (line 9) = Total Area NQC (line 4) + Incremental NQC from Renewable Construction (line 5) + Incremental Preferred DSM (line 6) + Incremental Demand Response (line 7) - Retirements (line 8) - LCR Requirement (line 3)

Figure III-3
LCR Need in the Big Creek/Ventura Area (in MW)

		Low Need Sensitivity		Base Need		High Need Sensitivity	
		2011	2020	2011	2020	2011	2020
1	*1 in 10 Peak Load (latest IEPR, split to Area)*	4,613	5,186	4,613	5,186	4,613	5,186
2	*Transmission improvements that affect LCR*	0	578	0	578	0	0
3	*LCR*	2786	2781	2786	2781	2786	3359
4	*Total Net Qualifying Capacity in area as of 2010 plus new additions from scenarios (including supply side CHP additions)*	5497	5630	5483	5580	5468	5468
5	*Renewable Construction Scenarios including Potential New Renewable Resource Additions related to Conceptual RPS Transmission*	0	0	0	0	0	0
6	*Incremental Preferred Demand Side Management*	20	72	5	-106	0	-260
7	*Demand Response Resources*	266	502	264	361	262	220
8	*Retirements*	0	1947	0	1947	0	1947
9	**Surplus or deficiency**	**2998**	**1477**	**2966**	**1108**	**2944**	**123**

Surplus or Deficiency (line 9) = Total Area NQC (line 4) + Incremental NQC from Renewable Construction (line 5) + Incremental Preferred DSM (line 6) + Incremental Demand Response (line 7) - Retirements (line 8) - LCR Requirement (line 3)

IV.

OVERVIEW OF THE RESOURCE PLANNING PROCESS

A. Integrated Resource Planning Defined

Generation resource planning is the process of building a diversified portfolio of generation resources that balances the objectives of system reliability, environmental sensitivity and customer cost (including managing customer cost risks). Integrated resource planning (IRP) broadens this perspective by including demand-side options such as EE and DR (both event triggered and price responsive programs) as portfolio resources that are considered in parallel with generation resource options. Energy storage technologies do not fit cleanly as either the supply-side or demand-side resources, but are nevertheless a resource type that is appropriately considered in developing a diversified portfolio as part of IRP.

Typically, resource planning takes place within a defined geographical scope and with a single, vertically integrated utility. In this LTPP, analyses are presented for the combined distribution service areas of the three IOUs.[21] However, it is important to recognize that California is electrically interconnected with the rest of the western states. So, resource choices in California have consequences for grid operations in other states. California IOUs are part of the WECC, and the CAISO is subject to national reliability standards enforced through the North American Electric Reliability Corporation (NERC). The resource planning process must take IOU and CAISO obligations into account and assure that California does not unduly "lean" on other states for operational support.

[21] Some results are presented at a statewide level, including both investor-owned utility service areas and publicly-owned utility service areas.

B. The LTPP is not an IRP Process

In the 2008 LTPP proceeding, Energy Division staff commissioned a consulting report addressing current electricity industry practices regarding IRP.[22] This report noted a dichotomy between (1) "regulated jurisdictions" which do not allow retail choice and where utilities engage in IRP to develop a "preferred portfolio" of resources to serve customer load, and (2) "deregulated jurisdictions" where utility procurement activities are typically limited to competitive procurement for bundled customers and planning functions are often shifted to an independent system operator or regional transmission organization. California has a hybrid market structure. Regulated utilities meet the needs of their bundled customers through competitive market processes, and some customers are allowed competitive retail choice. The CAISO has responsibility for grid operations and reliability, and conducts transmission planning and local capacity needs assessments across multiple service areas. State policy objectives are effectuated through regulations and laws that impose obligations on all load serving entities. Markets exist where any buyer can contract with any seller located anywhere and specifically, not in the area where their customers are located. In this regulatory environment, the purpose and objectives of a system need determination as part of the LTPP proceeding remain unresolved.

In any case, the CPUC-Required Scenarios fall short of an IRP process, because they do not comprehensively address the broad range of resource choices available to California, nor investigate how trade-offs among available portfolio choices can effectively balance cost, reliability and environmental objectives. In particular, the CPUC-Required Scenarios are not designed in a manner that serves to develop an efficient strategy to achieve statewide greenhouse gas (GHG) objectives as adopted by Assembly Bill (AB) 32, do not investigate the trade-offs between renewable power and other preferred resources such as EE, and do not provide a clear

[22] Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California (Draft), Aspen Environmental Group and Energy and Environmental Economics, Inc., Prepared for the California Public Utilities Commission under R.08-02-007, September 2008.

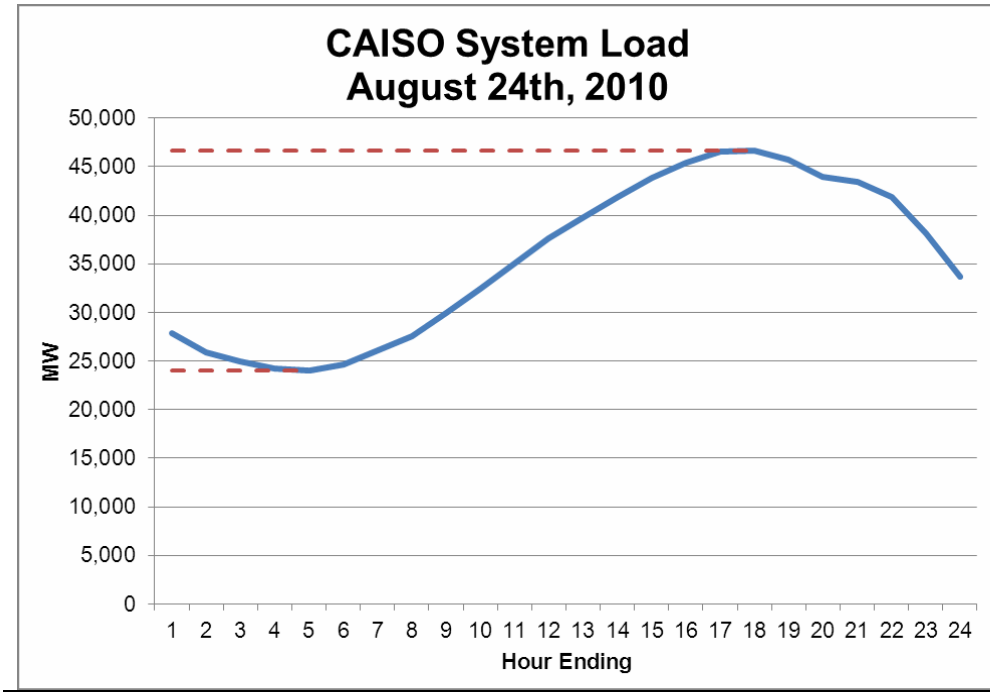
path to balancing competing environmental objectives such as air and water quality standards. Thus, it would be incorrect to designate any of the scenarios investigated in this LTPP proceeding as the result of a full IRP process.

The analyses presented in Track I of this proceeding are directed to provide useful research and to inform CPUC policy choices. They address some very specific questions regarding system reliability impacts associated with a buildout of renewable energy resources towards 33% over the next decade, and the need for renewable integration resources over this time horizon. Having identified such needs, SCE's preference is for the Commission to rely on competitive market institutions to the extent possible to address such needs, rather than presuming that such procurement should be the responsibility of the IOUs. Absent such competitive institutions, any procurement created should have the costs and risks of such procurement based on cost causation principles. Thus, in circumstances where procurement costs are incurred due to the need to ensure reliable electricity service caused by loads in a region, those loads should be responsible for those procurement costs. If system costs are incurred because some intermittent generation scheduled with the CAISO requires the CAISO to procure resources it would not otherwise need, then the costs of this procurement should flow to those providing intermittency to the grid, causing these costs. As the hybrid market system depends on the market to provide or offer resources to meet the need, SCE typically express product preferences through procurement evaluation criteria, but do not identify specific resource types to meet the identified need. None of the analysis presented by SCE in the current LTPP presumes any particular type of resource will be used to meet any particular need. Neither is there any presumption about who will procure or own the resources, or how the cost of the resources will be recovered. These issues are not subjects of the system planning analysis.

C. The Challenges of Effective Grid Reliability Modeling in the CAISO Area

An effective and appropriately diversified resource portfolio must have sufficient resources available both to meet overall system demand at peak periods and to follow the pattern of overall demand on a second-to-second basis, taking contingent conditions into account (such as the unexpected loss of a generation resource or variations in renewable energy output). Figure IV-4 shows an hourly load profile for the CAISO on August 24, 2010. The peak of 46,675 MW was below the annual peak of 47,282 MW experienced on the following day. However, this day is noteworthy because it represents a transition from a cooler weather pattern (lower night-time temperatures) to a hotter weather pattern (hotter daytime temperatures) and the trough-to-peak variation of 22,686 MW was the largest experienced in 2010. On this day, the peak hour-to-hour changes were +2636 MW between hour ending 10:00am (HE 10) and HE 11 and -4486 MW between HE 22 and HE 23. Not only did the CAISO need to have sufficient resources available in August 2010 to meet peak requirements (including holding resources in reserve for contingencies), it needed to have sufficient flexible resources available to meet hourly rates of change and the cumulative peak-to-trough variation.

Figure IV-4
CAISO Hourly Load Shape for August 24, 2010



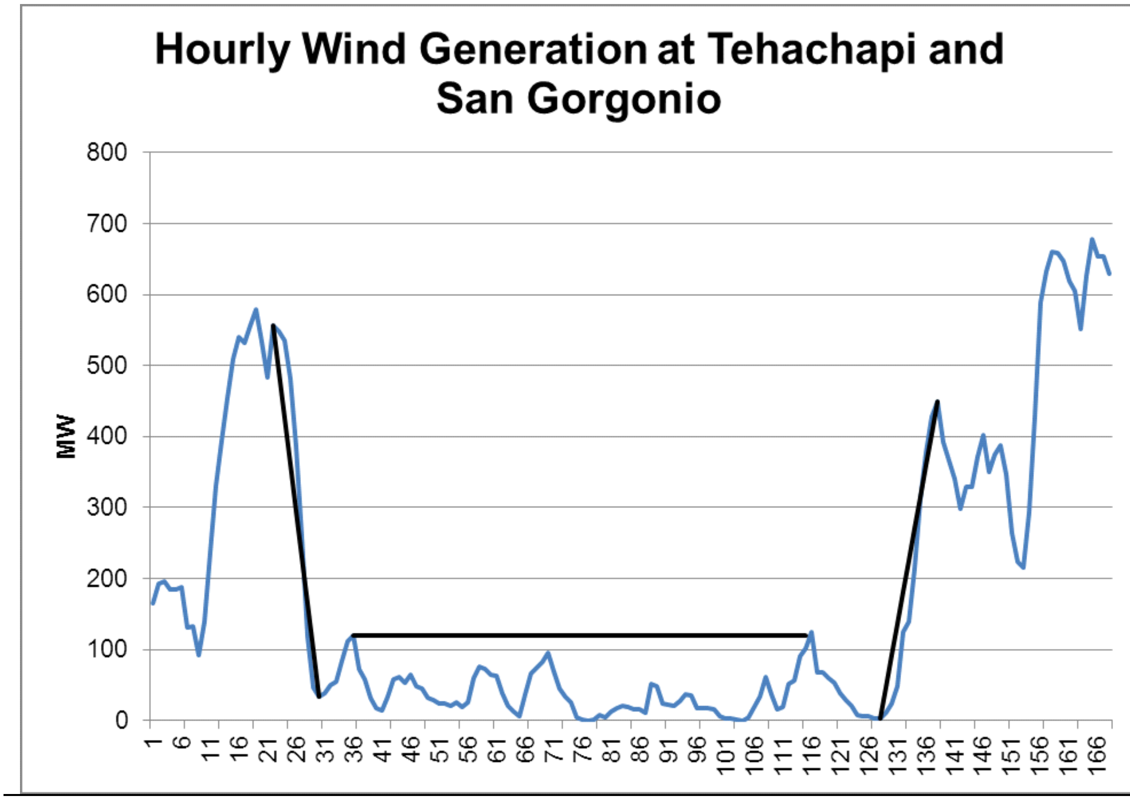
An expansion of solar and wind renewable resources makes the challenge of grid operations far more complex. These resources are intermittent and produce in response to environmental conditions, such as sunlight intensity and wind speed.[23] Figure IV-5 shows an hourly profile of wind generation from SCE's portfolio of wind resources for the peak week in 2010 (*i.e.*, the week in which the annual peak occurred). This figure reflects over 1,074 MW of contract capacity, generally distributed among two geographically dispersed areas (the Tehachapi mountains and San Gorgonio pass), so resource diversity is already reflected. Nevertheless, there is considerable variation in output, both hour-to-hour (as shown in the figure)

[23] Actual operational parameters are quite complex. For example, solar generation is affected by temperature, humidity and cloud cover in addition to sunlight intensity (insolation). Wind generation is affected by wind speed in a nonlinear manner, with wind turbines typical having minimum and maximum wind speed ratings, which vary by turbine type.

and within each hourly period. Over a seven hour period from 11pm on Sunday, August 22 to 5am on Monday, August 23, total wind output declined by 523 MW at a rate of 65 MW/hr. For the next 85 hours, wind output remained low. Finally, wind generation increased at a rate of 44 MW/hr for 10 hours from 8am to 6 pm on Friday, August 27. SCE's portfolio of older solar thermal facilities commonly employ supplemental natural gas firing, and thus do not experience the same level of output variability as wind resources. However, there is a general recognition that newer solar thermal facilities and photovoltaic solar facilities will experience output variability somewhat similar to the pattern evident for wind resources. This variation places additional stress on grid reliability, since flexible resources are needed to meet the combined influences of load following requirements and intermittent resource shaping needs.

As California increases its reliance on intermittent and non-dispatchable resources to meet RPS and other environmental objectives, there will be a tendency for these resources to displace the energy from older fossil-fueled resources that are typically dispatchable and capable of responding to diurnal peak-to-trough variations in load and "firming/shaping" in response to renewable intermittency. As a result, the remaining dispatchable resources will be required to carry a greater burden of operating flexibility.

Figure IV-5
SCE Hourly Wind Deliveries, Week of August 23, 2010



D. Building a Diversified Portfolio of Generation Resources

It is common for those engaged in resource planning to generalize resource attributes into three broad categories: baseload, intermediate and peakers. Baseload generation generally has low operating (running) costs, but has higher initial capital costs. Baseload plants, primarily nuclear, coal and large customer cogeneration facilities, are cost effective only if operated with a high annual load factor, so that the high initial capital costs can be amortized over a large quantity of output. In addition, nuclear and cogeneration plants are generally considered to be must-take resources, because the nature of their operations makes curtailment during low load periods impractical. As a result, a diversified portfolio generally relies on baseload generation only to the extent there is sufficient off peak demand to allow for around-the-clock operations.

Intermediate plants are generally intermediate in operating costs and initial capital costs, and flexible in operational characteristics. Such plants, including older natural gas-fired steam turbines and newer natural gas-fired CCGTs, can adjust their output level over a wide range with ramp rates commonly in the range of 3 to 5 MW/minute. Steam turbines may take six hours or more to start up and are impractical to cycle in daily operation (turning on and off each day creates mechanical stress that raises maintenance costs and lower reliability). As a result, steam turbines are commonly run during low-load nighttime periods to be available for operation the following day. CCGTs, which are comprised of a combination of peakers, a waste-heat recovery steam generator (using exhaust heat from the peaker) and a steam turbine, are somewhat more flexible — the peaker can start quickly and run stand-alone until the boiler reaches operating temperature.

Finally, peakers are relatively expensive to operate but have lower initial capital costs, and can be started quickly — often between 10 and 30 minutes. CTs, (essentially a stationary jet engine) are commonly used as peakers in California. The CAISO can use CTs on a planned basis during forecast peak conditions after placing all available baseload and intermediate resources into operation. But more commonly, CTs are held in reserve and used to meet load during unexpectedly hot weather, or turned on due to an outage of a generation resource or transmission line and operated until an intermediate resource can be started. SCE can also use hydroelectric plants (hydro) with water storage (*i.e.*, a dam or other water impoundment) as peakers, but because the available water is limited, hydro plants are generally constrained to operate only when needs are greatest. (Hydro plants can also be used to supplement the load following and renewable integration shaping requirements of intermediate resources.) SCE can also use DR resources as peakers, but DR resources are generally restricted in terms of their annual or monthly number of calls in order to maintain customer acceptability.

An additional resource planning challenge is managing grid operations during low load nighttime periods. Additional renewable generation (predominately wind, but also baseload renewable technologies such as geothermal and biomass) adds to generation during these low nighttime periods. Similarly, larger efficient cogeneration facilities also run in baseload operation. Increasing reliance on renewable resources and cogeneration facilities can create over-generation situations where there is insufficient demand to accommodate available must-take supply resources. Generally, the most difficult operational periods are in the spring. This is when loads are low, solar output is high, and hydro facilities receive additional water supplies from melting snow pack. Wind resources also contribute to such operational problems because they deliver substantial amount of energy in relationship to their contribution to meeting peak load period requirements. Figure IV-5 illustrates this problem — output is low during the peak period in 2010, and much higher immediately before and after this period. To the extent purchase from renewable and cogeneration projects are made at a fixed price, this results in customers paying a positive price for the project output and then selling this output at a negative price. In 2010, the South of Path 15 (SP15) region in which SCE's service area is located experienced 224 hours of negative prices that averaged negative $11.70 per MWh.

Traditionally, resource planners have used production simulation models to forecast grid operations over a multi-year planning period. Production simulation models start with a listing of available generation resources (including demand response resources as part of supply) and hourly load patterns for each year (8,760 hours) or for a typical week each month. The load forecast is reduced for energy efficiency and customer self-generation that is not already reflected in the trend analysis used to forecasts loads. The first modeling step is to commit (*i.e.*, start up, in the case of slow-start units) a selection of resources to operate over each weekly period, taking minimum and maximum loads and a planning reserve margin into account. The next modeling step is to dispatch the committed resources hourly over the weekly period on a least cost basis. Typical outputs of this simulation are energy production by resource, portfolio cost, time on margin by resource (how often each resource is the highest cost resource dispatched) and the corresponding running cost of these at-the margin resources (marginal cost).

Commitment algorithms in production simulation models typically do not capture requirements to respond to load and resource variability. This is seldom a problem, because existing resources have substantial flexibility and weekly commitments will commonly provide adequate load following capability. Resource planners performing production simulation modeling will inspect model outputs, and may make adjustments where results are implausible based on past experience. An example might be to restrict the commitment of a 750 MW unit when actual system operation would probably require two 330 MW units or three 215 MW units to be started to supply adequate ramping rates.

The variability of many types of renewable resources that are expected to become operational over the next 5-10 years, along with the potential retirement of older steam plants creates unprecedented challenges for appropriately modeling resource commitment and assessing the ability of future resource portfolios to operate reliably. Given these substantial changes, the ability of a resource portfolio to meet load following and intermittent resource shaping must be explicitly tested, rather than assumed. Both the CAISO and SCE have begun to use an optimization model (PLEXOS) developed by Energy Exemplar for resource planning. The PLEXOS model creates a set of mathematical optimization tools that search for the lowest cost commitment/dispatch solution (of an "objective function" equation that equals total WECC costs), subject to a series of constraint equations. The characteristics of the electricity grid are captured in the constraint equations entered by the user. For instance, constraint equations for a generating unit would include its minimum operating rate (Pmin), its maximum operating rate (Pmax), its start profile (the time it takes the unit to start), its ramp rate (maximum rate of output change in megawatts per minute), and so forth. The objective function would include a cost element based on the number of times this unit is started and its running cost. Other sets of equations set hourly generation equal to hourly load, and specify transmission topology and constraints. The entire WECC is modeled.

Assessing renewable integration needs in PLEXOS is a two-step process. First, five minute profiles for prototypical renewable resources (by technology and location) are developed, and this information, along with a specific renewable resource portfolio buildout is input into a simulation model developed by Pacific Northwest National Laboratory (PNNL). This is the Step 1 analysis and the output is the amount of ancillary service needs (ramping and regulation) required to shape the renewable output. For instance, simulation of a particular portfolio might produce a finding that grid operators need to have 3,000 MW of upward ramping flexibility and 4,000 MW of downward ramping flexibility available during April. These ancillary service needs (six types in total) are then entered into the PLEXOS model database as constraint equations. Step 2 consists of running the PLEXOS optimization subject to these (and the other) constraints. The specific modeling technique used is to introduce relaxation parameters (also calls constraint penalties) that allow the equations to solve without satisfying the ancillary service constraints, but impose a high cost based on the amount by which each constraint is violated. If the equations solve with a non-zero value for any of the relaxation parameters, this is a constraint violation and the inference is that there are insufficient physical resources to meet renewable integration needs. Resource planners then add additional generic resources to the system until there are sufficient resources to "clear" the constraint violations.

A noteworthy aspect of the PLEXOS modeling approach used in this proceeding is that the regional configuration of the equations effectively allows renewable integration needs to be met from resources throughout the WECC prior to triggering a constraint violation. This is appropriate for a <u>physical</u> representation of the grid, but does not address the <u>contractual</u> aspects of "exporting" California's renewable integration needs to other states. Other states may either seek to limit California's use of out-of-state flexible resources or may impose costs for such use.[24] As a result, the renewable integration requirements identified through PLEXOS modeling are likely to be a lower bound on actual requirements.

E. The Challenge of Addressing Transmission Issues

In general, generation resource planning takes place separately from, but in parallel, with transmission system planning. Much of the process of performing transmission system analysis deals with grid reliability during particularly stressful conditions, such as during high load periods or when major system components (large generators and/or high voltage transmission lines) are out of service. Transmission system analyses tend to focus on stable "snapshot" conditions, such as whether transmission facilities are overloaded during stress conditions, or transient conditions, such as whether the grid is able to respond to an exogenous shock, such as the sudden loss of a generating unit. This is much different than generation system planning, which focuses on a long-term time horizon, and assesses performance on a (typically) hourly basis over the course of the time horizon. Transmission planning models contain detailed topology of grid components, and much less information about generator operating characteristics.

There are a number of ways in which transmission planning information finds its way into generation resource planning activities. To the extent that generation resource planning projects an expansion of imported power, the timing of these imports (and the associated costs) may be contingent on construction of new transmission lines. Under the various RPS scenarios considered in this LTPP, there are different assumed transmission buildouts, for example. Another way in which transmission information is incorporated into generation resource planning is by reflecting transmission operating constraints into production simulation modeling. For example, two criteria enforced in the PLEXOS modeling in this LTPP (by including

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[24] For example, Bonneville Power Administration (BPA) has recently posted a Variable Energy Resource Balancing Service (VERBS) rate, which would be waived for renewable generators willing to dynamically schedule output to another balancing authority. *See* BPA Docket BP-12, testimony volume BP-E-BPA-29, November 19, 2010 http://www.bpa.gov/corporate/ratecase/2012/docs/bp-12-E-bpa-29.pdf

constraint equations which are included in the PLEXOS model optimization) are the Southern California import transmission nomogram limits (SCIT limits) and the import limitation of 60% of Southern California's load. In simple terms, SCIT limits describe trade-offs between maximum transmission imports from the north and east of the Southern California region — *e.g.*, as more power is imported from the north, the amount of power that can be imported from the east goes down. The maximum amount of total imports is limited to 60% of Southern California's load. Both of these criteria are design to assure that the grid operates reliably under contingent conditions.

Because of the different modeling approaches and techniques utilized in transmission planning, it would not be reasonable to attempt to do transmission planning jointly with generation resource planning. Instead, the results of transmission studies can be incorporated into generation resource planning as transmission needs become apparent. For example, SCIT limits are periodically reevaluated by the CAISO, and newer information can be incorporated into PLEXOS modeling as this information becomes available.

V.

[SCE SUBMITS IMPACTS OF SONGS SHUTDOWN IN THIS LTPP TRACK I FOR COMMISSION CONSIDERATION]

Women's Energy Matters (WEM) filed intervenor testimony in the LTPP Track II proceeding recommending the immediate shutdown of San Onofre Nuclear Generating Station Units (SONGS 2 & 3). SCE objected to the submission of WEM's testimony as being outside the scope of Track II, and SCE does not think the issue is relevant to Track I of the LTPP. The scenario of a SONGS 2 & 3 shutdown is not a scenario identified in the scoping ruling issued by the Commission for this LTPP. Further, the Commission has indicated its preference to consider nuclear issues (*e.g.*, funding of seismic studies and funding of license renewal activities) in separate proceedings focused solely on those issues.[25] However, the Administrative Law Judge (ALJ) overruled SCE's objection, and allowed testimony regarding an immediate shutdown of SONGS 2 & 3 in Track II. Therefore, SCE includes the following testimony response to the issue raised by WEM in the event the Commission wishes to consider the issue in Track I of the LTPP.

Track I of this LTPP focuses on determining what, if any, integration needs arise associated with future resource considerations that achieve the State's 33% RPS. The scenarios ordered by the Commission and those analyzed by the IOUs all focus on determining, under differing assumptions, what level of new generation resources would be needed by 2020 to ensure that the CAISO can meet its operating criteria. Each of the resource plans that are developed for 2020 with the additions necessary to satisfy CAISO operating criteria, are evaluated using a series of metrics established in prior ALJ rulings for this case. The impacts of a premature[26] SONGS 2 & 3 shutdown are entirely different than the studies that have been

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[25] *See* March 1, 2011 Scoping Memo in SCE's Test Year 2012 General Rate Case (A.10-11-015), p.15.

[26] A premature shutdown is removing SONGS 2 & 3 from service prior to the expiration of the current operating license in 2022.

conducted. There would be additional resource needs to satisfy CAISO operating requirements that could be identified if SONGS 2 & 3 were assumed to be prematurely shutdown , and such analysis does not capture the serious grid reliability and economic implications of such a scenario. Analyzing these additional resource needs is an iterative process that includes: (1) identifying replacement generation of equivalent capacity and volume, (2) conducting detailed transmission studies depending on replacement generation location, and (3) making adjustments to replacement generation options based on the transmission study results. Such studies would take considerably more time, different modeling and expertise, and focus on different metrics than Track 1 considers. SCE strongly urges the Commission to keep the LTPP scope consistent with all of the Commission's prior orders in this docket, and not consider making any decisions relating to the future of nuclear operations at SONGS as there will not be an adequate record in this proceeding.

To attempt to consider a premature shutdown of SONGS 2 & 3 in this proceeding would require an extensive preparation of analyses of the potential impacts of such a shutdown including more information than can be adequately developed for this record. SCE's discussion below provides only a high-level summary of the problems associated with a premature shutdown of SONGS 2 & 3.

SONGS is the largest electric generation plant in southern California and has been an integral part of the electric grid in southern California for 43 years. The immediate and premature shutdown of SONGS 2 & 3 would directly impact southern California electric system reliability, affect the state's ability to meet its environmental goals, and have a substantial negative effect on electricity and gas prices.[27]

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[27] Consideration of electric system reliability, environmental impacts, and electricity and natural gas prices would need to be addressed in other nuclear proceedings outside of this LTPP.

Actions to mitigate the impact of an immediate shutdown of SONGS 2 & 3 would be complex, controversial, environmentally sensitive, and time consuming. In any event, those actions necessary to mitigate the loss of SONGS 2 & 3 could not be implemented quickly enough to offset the immediate adverse impacts of shutting down the units.

A. The Premature Shutdown of SONGS Would Have Immediate and Adverse Impacts on Electric System Reliability

Electric system reliability in southern California would be immediately and adversely impacted by a premature shutdown of SONGS 2 & 3, especially in the SCE and SDG&E service territories. SONGS 2 & 3 not only supplies a significant and reliable source of electric generation for customers, it is vital to the safe and reliable operation of the electric grid in support of state and federal performance standards.[28] Specifically SONGS 2 & 3 provides critical voltage support, import capability, and transient stability support to the electric grid for SCE and SDG&E service territories that cannot immediately be replaced by other sources.

Preparing the grid to offset the impacts of removing SONGS 2 & 3 from service at the end of their current license period would be tough but manageable. However, if the support that SONGS 2 & 3 now provides the grid was eliminated prematurely, the electric grid would immediately become vulnerable to reliability failures. Preserving the integrity of the electric grid in these conditions would likely require, in the short term, disconnecting customers by implementing controlled rolling blackouts[29] to reduce the stress on the electric grid until the immediate risk of electric grid failure has passed.

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28 Applicable system-reliability standards include those issued by the CAISO, WECC, and NERC.

29 The implementation of controlled rolling blackouts would likely occur under moderate to heavy load conditions, and would continue to occur intermittently. Controlled rolling blackouts would be implemented in accordance with operating procedures and nomograms; however these procedures would need to be revised to account for the long-term outage of both SONGS units.

The CAISO reached these same conclusions. In its March 21, 2011 "Qualitative Assessment of Removing San Onofre from Service" memo, [30] the CAISO stated the following:

> "Local capacity requirements are impacted more severely by the loss of SONGS 2 & 3 (even more than Diablo Canyon). It is expected that local capacity requirements for the LA Basin cannot be met over the heavy load months with the shutdown of both SONGS 2 & 3 units without dropping load and the availability of all existing gas-fired generation in the LA basin and San Diego. Voltage stability issues would be encountered first, but thermal limits will be close behind.
>
> This scenario has not been studied recently but previous studies indicated that the shutdown of SONGS 2 & 3 would also affect reliability of supply into southern California more broadly, and would require significant infrastructure upgrade, possibly new transmission beyond that which the ISO has already identified as needed, and the continued operation of the existing gas-fired thermal fleet in southern California."

The analysis to determine grid reliability implications and associated transmission upgrade needs is conducted within the CAISO's grid planning processes, and has not been the subject of careful consideration in any prior LTPP proceeding.

B. There is Not Enough Time for Mitigation to Avoid the Negative Impacts of an Immediate Shutdown of SONGS

Mitigation of the detrimental impacts of a SONGS 2 & 3 shutdown will take a minimum of 7 years under the current regulatory framework, and will likely take up to 10 years. In order to mitigate grid vulnerability of a SONGS 2 & 3 shutdown, substantial amounts of in-basin generation[31] and/or additional transmission would have to be constructed and connected to the grid. Construction of high voltage transmission lines and multiple generation facilities to mitigate an immediate SONGS 2 & 3 shutdown would necessarily involve many imposing challenges with an uncertain timetable and possible outcome. The licensing process for high voltage transmission, for example, involves lengthy regulatory review of the siting, design, and

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[30] *See* March 21, 2011 e-mail from Yakout Mansour, CEO CAISO to Ronald Litzinger, President Southern California Edison (attaching March 21, 2011 CAISO memo).

[31] Assumed replacement generation is 2,150 MW of combined cycle gas turbines.

environmental impacts of such projects, all of which can and has in the past lead to major project changes and delays. In the course of the transmission licensing process, there is substantial risk that some transmission projects or portions of such projects will turn out to be infeasible or environmentally unacceptable. As stated above, SCE estimates that 7 - 10 years is needed for this process.

C. A Premature Shutdown of SONGS Would Impact State Environmental Goals

In addition, a premature shutdown of SONGS 2 & 3 would have substantial adverse environmental impacts that would significantly affect the ability of the State to achieve its climate change and air quality goals. For example, the incremental emissions associated with generating replacement electricity with fossil fuels would include 6-10 million metric tons of CO2 equivalent/year; 280 metric tons of NOx/year; and 1,100 metric tons of PM-10/year (particulate emissions).[32] SCE bases these rough estimates on having to immediately replace the lost SONGS 2 & 3 generation with additional natural gas generation from existing units, and ultimately with the addition of new natural gas generation.[33] As noted previously, the assumption of just replacing the power generated by SONGS 2 & 3 does not resolve significant reliability issues due to the locational characteristics of SONGS 2 & 3.

D. SONGS Shutdown Would Have a Negative Economic Impact to Southern California

If SONGS 2 & 3 were shutdown prematurely, the replacement power cost would be substantially greater than SONGS 2 & 3 generation cost.[34] The cost of additional GHG mitigation measures to offset the increased emissions from SONGS 2 & 3 replacement with natural gas generation would be substantial, if feasible. The increased natural gas requirements

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[32] 1,100 metric tons of PM-10/year is approximately three to four times the current South Coast Air Quality basin PM-10 emissions.

[33] In the specific scenarios evaluated as part of this LTPP, replacing both SONGS and Diablo Canyon generation would increase CO2 equivalent emissions by 15 million metric tons/year. *See* Exhibit Joint IOU-1, Appendix B.

[34] *See* March 1, 2011 Scoping Memo in SCE's Test Year 2012 General Rate Case (A.10-11-015), p.15.

due to replacement of SONGS 2 & 3 generation with natural gas would cause increased natural gas prices for all of southern California. The reduction in electrical supply from the loss of SONGS 2 & 3 generation, before new generation could be built to replace it, would increase electricity market prices in CAISO and bilateral markets throughout California (*i.e.*, the increased price of natural gas would exacerbate the electricity market price implications and GHG cost implications of reduced generation supply in the market). The potential for price spikes due to supply shortages or even market manipulation would be increased absent such a large provider of generation to the market. All of these factors and more would increase electricity prices in California in the event of a premature SONGS 2 & 3 shutdown. The quantification of these and other impacts on the California economy would require substantial analysis that is outside the current scope of anything in Track I, II, or III of this LTPP. So, SCE can see no way in which an adequate record could possibly be established in Track I to address a nuclear shutdown scenario.

In conclusion, SCE strongly urges the Commission to focus the efforts of this LTPP on the Commission's previously defined scope, and not allow the interest of some intervening parties to subvert the process for an agenda that cannot lead to any decision on the subject that could be supported by an adequate and fully developed record in this proceeding.